TABLE 1. NEW SOURCE PERFORMANCE STANDARDS FOR COAL-FIRED ELECTRIC UTILITIES

Pollutant	1971 Maximum Allowable Emissions	1978 Maximum Allowable Emissions
Sulfur Dioxide	No more than 1.2 pounds per million Btus of any coal consumed	No more than 1.2 pounds per million Btus of fuel consumed, plus 90 percent emissions reduction, or no more than 0.6 pounds per million Btus of fuel consumed plus 70 percent emissions reduction
Nitrogen Oxide	No more than 0.7 pounds per million Btus of all anthracite, bituminous, and subbituminous coals consumed; 0.6 pounds for lignite [a]	No more than 0.6 pounds per million Btus of all anthracite, bituminous, subbituminous, and lignite coals consumed
Particulate Emissions	No more than 0.1 pounds per million Btus of fuel consumed	No more than 0.03 pounds per million Btus of fuel consumed

SOURCE: Congressional Budget Office, from Environmental Protection Agency.

NOTE: For emissions limits for oil- or gas-fired utility plants, see 36 Federal Register 15703 (December 23, 1971) and 44 Federal Register 33580 (June 11, 1979).

a. Anthracite, bituminous, subbituminous, and lignite are types (or ranks) of coal, differentiated by inherent differences in chemical composition.

Emission Patterns Under Current Policy

In 1985, utility power plants emitted roughly 15.8 million tons of SO_2, representing between 60 percent and 70 percent of the annual SO_2 man-made emissions in the U.S.[3] By 1995, in the absence of any new regulations, this figure should grow to about 18.5 million tons per year as new plants are built

3. The percent of national sulfur dioxide emissions contributed by utilities is based on projected and historical figures presented in Office of Technology Assessment, *Acid Rain and Transported Air Pollutants: Implications for Public Policy* (June 1984), p. 60.

to meet growing demand for electricity.[4] Most of the SO_2 discharged in 1985 came from utility plants built before the first NSPS was enacted in 1971--a trend that will continue through 1995. In fact, over 97 percent of the 15.8 million tons of SO_2 released in 1985 was from older plants covered solely by state emission standards, and not from newer plants covered by the NSPS. By 1995, these pre-NSPS plants will still contribute 90 percent of all utility sulfur dioxide emissions. The remainder of emissions will be from plants built under either the first power plant NSPS of 1971 or under the more recent one of 1978. Thus, older, pre-NSPS sources will be the target of any new strategy to reduce utility SO_2 emissions, since NSPS-covered plants already are well-controlled and offer little room for further reductions.

Expected Growth in Coal Use Under Current Policy

From 1985 through 1995, the amount of coal mined in the United States is expected to grow by almost 30 percent--from 883 million tons in 1985 to 1,129 million tons in 1995. Almost all of the projected growth can be attributed to electric utilities since they use, on average, over 80 percent of all coal mined. Over two-thirds of this increase will occur in the eastern states of West Virginia, Kentucky, and Pennsylvania. Another one-quarter of the production rise will occur in Texas alone. In contrast, the midwestern states of Ohio, Indiana, Illinois, and Missouri could face over a 10 percent decline in coal production over the period, while the major western coal-producing states--Montana and Wyoming--are expected to maintain about current production levels.

Similarly, the level of coal mining employment could rise over 30 percent by 1995, based on coal mining productivity figures currently available. Most of the job growth also will take place in the eastern states; midwestern job levels are expected to decline slightly, while those in most western states are anticipated to rise somewhat.

Regional Coal Characteristics and Coal Prices

In general, U.S. coal production can be divided into three regions: the East, where the productive Appalachian region spans West Virginia, Kentucky, and

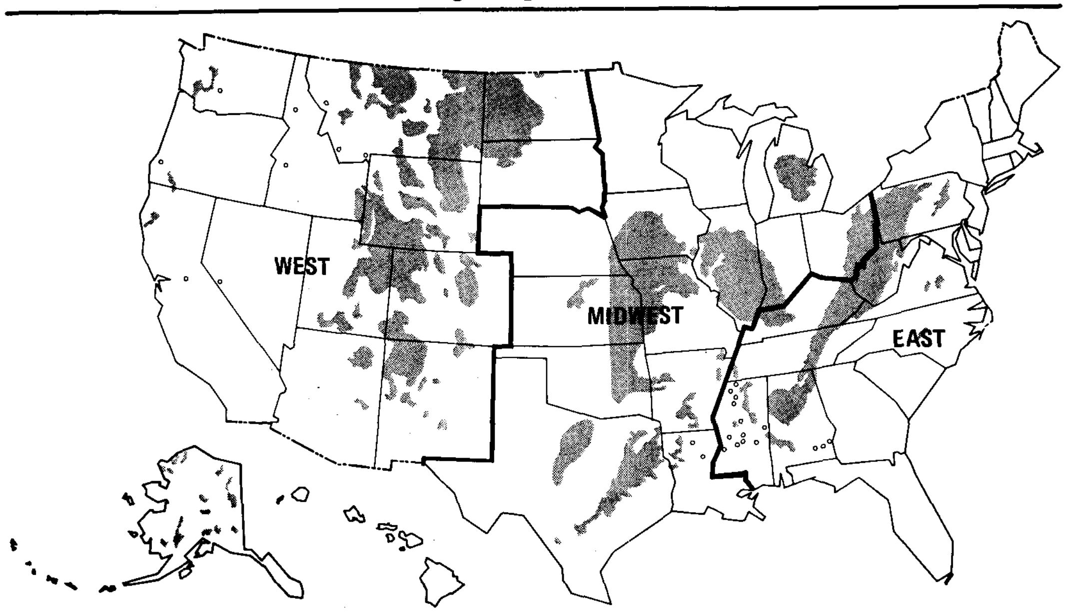
4. Utilities also emit substantial quantities of nitrogen oxides and particulate matter. In 1985, roughly 6.6 million tons of nitrogen oxides and 1.3 million tons of particulate matter per year were emitted by power plants. These emissions are expected to grow to 8.7 million tons per year for nitrogen oxides and 1.6 million tons per year for particulate matter by 1995. Nevertheless, sulfur dioxide emissions remain the subject of this study.

Pennsylvania; the Midwest, which contains the abundant Illinois coal basin and Texas lignite fields and extends to the western borders of Minnesota, Nebraska, Kansas, Oklahoma, and Texas; and the West, which contains several major coal basins throughout Montana, Wyoming, Colorado, New Mexico, and Utah. (Figure 1 depicts each of the major coal-producing regions in the continental United States.) Coals mined in each of these regions generally possess different characteristics, including the method by which they are obtained (either deep mined, or "stripped" by surface mining techniques), energy content, and the amount of sulfur contained by weight. Each of these characteristics can affect the delivered price of the coal, as can the distance it must be transported.

The **mining method** used is the most important determinant of coal prices. Surface mining is generally more productive (and less expensive) than deep mining (see Table 2). Surface mining can only be used, however, where the coal is close to the surface and accessible to equipment, and where the land can be economically reclaimed after mining.

In the East, the choice of mining method is roughly split between surface (40 percent) and deep mining (60 percent). The cost for coal mined underground in the East can range from $30 to $46 per ton (as measured by

Figure 1.
U.S. Coal Fields and Producing Regions



SOURCE: Adapted by the Congressional Budget Office from the President's Commission on Coal, "Coal Data Book" (February 1980).

TABLE 2. COAL COSTS AND AVERAGE SULFUR CONTENT OF COAL, BY REGION [a]

	Cost in 1985 Dollars (In dollars per ton)			
	Under-ground	Surface	Average	Average Sulfur Content (In percents) [b]
		East		
Alabama	45.55	43.82	44.66	1.5-1.7
Georgia	N.A.	w	w	w
Kentucky, East	30.99	28.98	29.78	0.9-1.2
Kentucky, West	29.86	26.55	27.91	2.3-3.5
Maryland	w	w	29.18	1.5-1.6
Pennsylvania	39.43	30.52	34.85	1.9-2.1
Tennessee	31.12	27.76	30.18	1.2
Virginia	32.49	32.26	32.45	1.0-1.1
West Virginia	36.28	32.56	35.58	1.1-2.0
		Midwest		
Illinois	32.68	28.73	31.12	2.7-3.1
Indiana	w	w	26.00	2.3-2.9
Iowa	w	w	26.36	w
Kansas	N.A.	28.01	28.01	3.5-4.4
Missouri	N.A.	25.57	25.57	3.6-5.0
Ohio	43.95	29.21	34.53	3.5
Oklahoma	N.A.	33.45	33.45	1.9-3.6
Texas	N.A.	11.60	11.60	1.2-1.7
		West		
Arizona	N.A.	w	w	w
Colorado	28.48	21.54	24.02	0.5-0.6
Montana	N.A.	14.13	14.13	0.6
New Mexico	w	w	20.20	0.5-0.8
North Dakota	N.A.	9.87	9.87	0.9-1.0
Utah	30.40	N.A.	30.40	0.5
Washington	N.A.	w	w	w
Wyoming	w	w	12.38	0.5

SOURCE: Department of Energy, Energy Information Agency, *Coal Production 1984* (November 1985).

NOTES: N.A. indicates no reported production over 100,000 tons; w indicates data withheld to avoid disclosure of individual company data.

a. Coal costs are measured by mine-mouth prices.

b. As measured by shipments to electric utilities and "other industrial" users, in percent of sulfur by weight.

mine-mouth price); for coal mined by stripping, from $27 to $44. In the Midwest, most coal is mined by surface methods, although some underground mining takes place. Midwest strip-mining costs run from $12 to $34 per ton, while deep-mining costs run from $33 to $44 per ton. Finally, most western coals are close to the surface and are, therefore, extracted by strip-mining methods. These western surface mines are typically more productive than either eastern or midwestern surface mines, and have extraction costs ranging from $10 to $22 per ton.[5] Even accounting for the fact that many western coals contain 25 percent less energy than most midwestern and eastern coals, the difference in mining costs is still significant. (Assuming a 25 percent difference in energy content, an amount of western coal equal to a ton of eastern coal would only cost between $12.50 and $27.50 to mine, still less than all other types, except Texas lignite.)

After mining costs, the most important factor affecting the delivered price of coal is the **distance it must be transported**. Most coal moves by rail during some if not all of its trip to utility plants. Rail haulage rates generally range from 20 mills to 40 mills per ton for each mile carried (called a "ton-mile"), with western rates generally lower than those in the East.[6] At a cost of 25 mills per ton-mile, a haul of 300 miles can increase the mine-mouth price of coal by $7.50 per ton. For 1,000 mile hauls, $25 can be added to the price of each ton of coal. Though unusual in the East, where coal hauls average 300 miles, hauls of 1,000 miles or more are not uncommon for coal originating in the West. Thus, by the time a western coal reaches a midwestern destination, its original purchase cost might have doubled. Moreover, because of the typically low energy content of western coals, more must be shipped than if eastern or midwestern coals--which have higher energy contents--were used.

A third factor affecting delivered price--and one more difficult to quantify--is **sulfur content** (see Table 2). About 95 percent of the sulfur contained in fossil fuels is converted to sulfur oxides during combustion in most power plant boilers. If not controlled, these oxides are released to the atmosphere along with the other combustion gases. A simple limit on sulfur dioxide emissions would allow utilities to choose the method of control: either installation of a scrubber or a switch to low-sulfur coal. The

5. See Department of Energy, Energy Information Administration, *Coal Production 1984* (November 1985). All costs have been adjusted to 1985 dollars.

6. For example, western coal can be shipped to the mid-Atlantic region at a rate of about 17.2 mills per ton-mile as compared with mid-Atlantic intraregional shipment rates that may cost 38 mills per ton-mile. (Mill rates have been adjusted to reflect 1985 dollars.) See Department of Transportation, *1984 Carload Waybill Statistics* (1986).

difference between these two choices can be thought of as a low-sulfur fuel premium. Using a scrubber adds about 8.8 mills per kilowatt-hour (kwh) of electricity generated, which is equivalent to adding roughly $21 per ton to the price of coal being burned. 7/ Therefore, a plant manager could purchase a low-sulfur "compliance" coal that costs up to $21 per ton more than a "scrubbed" high-sulfur coal and still spend less than if he chose to install a scrubber. (This example assumes the energy content of both coals is similar.) Thus, sulfur dioxide emission limits can influence the choice of coal. High-sulfur coal can become less valued, resulting in shifts in geographic coal-market patterns.

EFFECTS OF REQUIRING ROLLBACKS IN SULFUR DIOXIDE EMISSIONS

Proposals to control acid rain would change emission, cost, and coal-market patterns from those expected under current policy. This section examines two options--one would require that utilities reduce their SO_2 emissions by 8 million tons from 1980 levels; the other would require a 10 million ton SO_2 reduction from 1980 levels (only plants operating as of 1980 would be affected). 8/ Both options assume the enabling law would go into effect in 1986 and that the utilities would be given until 1995 to comply with the regulations.

The rollback levels chosen encompass the most common range of reductions contained in legislative proposals to date. The formula used to assign the emission reductions to each state is called the "excess emission" formula, also a common item in acid rain control bills. 9/ In essence, the excess emissions formula first calculates for each state the total amount of

7. Figures based on a 500 megawatt (Mw) plant using a scrubber costing about $240 per kilowatt of capacity at an interest rate of 10.8 percent (nominal) and on operation and maintenance cost of 4 mills per kilowatt-hour. Assumed scrubber life is 30 years (for a new plant). Capacity factor for plant is assumed to be 65 percent. Values represent first-year costs in 1985 dollars. See also Department of Energy, Energy Information Administration, *Cost and Quantity of Fuels for Electric Utilities, 1984* (July 1985), Table 37, for a range of scrubber capital and variable costs.

8. 1980 is commonly used as a baseline because it represents a year of measured emissions that do not include power plants operating under the 1978 NSPS. Even though more recent data may be available, 1980 remains the baseline of choice.

9. For a list of recent proposals and general comparisons, see Larry Parker, "Acid Rain: Issues in the 99th Congress," Congressional Research Service, October 22, 1985. Two recent proposals, S. 2203 and H.R. 4567, are discussed in Chapter VI of this report.

SO_2 discharged in 1980 by each plant that was over 1.2 pounds of SO_2 per million British Thermal Units (Btus). National allocation ratios for each state are then derived by dividing each state's share of excess emissions by the national total of excess emissions. Each state's reduction amount would be determined by multiplying its ratio by either 8 million tons or 10 million tons, depending on the applicable national reduction goal. Other methods could of course be used--such as simply assigning an emission limit for all plants--but the excess emissions formula remains the most popular.

In the options of this chapter, each state would be allowed to develop an emission reduction plan to meet its respective goal, much like current strategies for meeting existing air quality standards. Because reductions would be set at the state, and not the plant, level, states would be free to develop the most cost-effective plan to control utilities within their territory, a condition reflected in this analysis. Such plans could include "emissions trading," through which plants having lower marginal control costs could sell SO_2 reductions to plants with high marginal control costs within the same state, as long as statewide reduction targets were met. (The appendix describes 1980 emission levels and the required reductions for each state according to the allocation formula for 8 million and 10 million tons.) 10/

Methodology

To analyze the SO_2 rollback options, the Congressional Budget Office used a computer-based simulation model that portrays utility emissions, utility costs, and coal-market supply and demand patterns under different policy assumptions. The model, called the National Coal Model, is maintained by the Department of Energy.

10. Two items are important to note about these emission reduction options. The first is that each requires only a reduction from 1980 emissions, meaning that after lowering emissions from 1980 levels by 8 million tons or 10 million tons annually, emissions growth from sources built after 1980 would be allowed to occur. This is to be distinguished from an emissions "cap," designed to hold total statewide emissions to some predetermined level. An emissions cap would require much greater initial reductions so that new source emissions could be accomodated. The second point is that this study uses 1985 and 1995 as base years from which to make comparisons, while still using 1980 as the basis for determining how much reduction should occur. For both of these reasons, the 8 million ton and 10 million ton emission reduction cases, using 1980 as a base year, show only about a 7 million ton and 9 million ton rollback, respectively, when 1995 levels under each option are compared with 1995 levels expected under current policy. This discrepancy is caused by the emissions growth that would occur between 1980 and 1995.

The model estimates the cheapest way to produce electricity nationwide, taking into account the cost of purchasing coal from different regions, the expense of transporting it, the cost of using different types of power plants as well as building new ones, and the effect of different emission regulations. Coal is distinguished by its origination in 31 supply regions (more than the actual number of states that produce coal) for shipment to 44 demand regions (representing roughly each state in the continental United States). Coal is further differentiated by sulfur content, coal rank, and energy content, which are later used to determine the type of power plant in which it can be burned. Demand regions are defined, in part, by their prevailing emission regulations and expected growth in electricity demand.

After a particular policy scenario has been established--including constraints on SO_2 emissions in each demand region--the model estimates an optimal solution based on the lowest annual real power cost that can be obtained in each region under the specified policy. Solutions are provided for three target years: 1985, 1990, and 1995. For this study, most policy changes were considered to be implemented fully by the 1995 solution year, with most comparisons among different options also based on that year. As part of this analysis, many assumptions used in the model were altered and portions of the computer code were revised. The appendix contains more details on these revisions and the methodology in general. In addition, caution should be exercised when interpreting model results (see box).

Emission Projections Under Each Rollback Option

Four different SO_2 rollback schemes are examined in this chapter: 11/

- **Option II-1A** would require an 8 million ton reduction of SO_2 from 1980 utility emission levels, allowing utilities to choose either fuel switching or scrubbers (whichever is cheaper) as a compliance strategy;

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11. Because of the many options discussed in this paper, CBO has devised a standard option format. The roman numeral identifies the chapter in which the options are presented--for example, option II appears in this chapter. In this chapter, the arabic number 1 identifies an 8 million ton reduction of SO_2, while the arabic number 2 identifies a 10 million ton reduction. The capital letters A and B identify the specific type of option--fuel switching or scrubbers, taxes and subsidies, and so forth. For easy identification, a glossary defining all the emission rollback options that appear in this and subsequent chapters is presented at the end of this report.

- **Option II-1B** would also require an 8 million ton rollback, but would restrict how much utilities could switch fuels by requiring that 80 percent of the same type of coal purchased in 1985 be purchased in 1995;

- **Option II-2A** is like Option II-1A above, but differs by requiring a 10 million ton rollback; and

- **Option II-2B** is like Option II-1B above, but again differs by requiring a 10 million ton rollback.

INTERPRETING MODEL RESULTS

To estimate the costs and coal-market effects of alternative acid rain control policies, CBO used the National Coal Model (NCM), which is housed and maintained by the Energy Information Administration (EIA). The NCM is a linear programming model, which has been used by EIA and other analysts to study the effects of fuel and transportation costs, government energy policies, and environmental regulations on national coal production and use in the electric utility industry.

Linear programming can provide the least costly (or "least-cost" in economic terminology) solutions to various problems concerning resource allocation. This particular linear program estimates the lowest annual electricity cost that can be attained in different U.S. regions, subject to constraints on how much sulfur dioxide can be emitted in each region, on where certain types of coal can be obtained and at what cost, and on the cost and effectiveness of scrubbers in reducing emissions. The model's results provide the least-cost solution for each policy. Real-life situations, however, rarely afford a least-cost solution because of small and varied inefficiencies present in all systems and behavior that does not replicate the ideal market. Moreover, in developing SO_2 reduction strategies, states may fail to specify least-cost emission reductions for utilities within their borders, a possibility that is not recognized in the model. Thus, when interpreting model results, it is important to remember that the costs shown for individual policy options probably reflect a lower bound of costs for that policy, with actual costs likely being higher. Conservative assumptions are used throughout the analysis to help counter this bias, though. More useful in many cases than absolute costs are the **differences** shown among optional policies. Thus, focusing on a $4 billion difference between two policies may be a more accurate reflection of costs than reporting that one policy costs $6 billion and the other $2 billion.

Options II-1A and II-2A would allow a choice in meeting reduction standards, much as the first utility NSPS of 1971 did. In contrast, Options II-1B and II-2B would mitigate production and employment losses in regional coal markets--particularly in the Midwest--by their tendency to "lock in" many current coal contracts. By denying such fuel flexibility, however, the second set of options would require more scrubbers, thus producing higher overall costs.

Both the 8 million ton and 10 million ton rollback programs would lower emissions substantially by 1995, although the differences between the 1995 predicted levels under current policy and either rollback option would reflect something less than the 8 million ton or 10 million ton goal specified, because of growth in new source emissions after 1980, the baseline year for measuring reductions. Under either scheme, the midwestern states of Ohio, Indiana, Illinois, and Missouri and the eastern states of West Virginia and Pennsylvania would face the largest emission reductions (see Table 3). Each of these states contains a large amount of coal-fired capacity that emits SO_2 in quantities greater than 1.2 pounds per million Btus of fuel input, the standard that serves as the basis of the excess emissions formula. In fact, many power plants in the Midwest (built before the first utility NSPS was issued) discharge SO_2 in excess of 6 pounds per million Btus under current state regulations.

To lower emissions significantly from these power plants, the utilities would have to use lower-sulfur coal or install scrubbers. If the midwestern plants wanted to switch to a lower-sulfur coal, they would have to import fuel from the East (Appalachia) or the West (Wyoming, Montana, or Colorado). In contrast, power plants in both West Virginia and Pennsylvania are closer to indigenous low-sulfur coal mines, and could use this locally available but more expensive fuel. In both cases, costs probably would rise.

Compared with power plants in the Midwest, Pennsylvania, and West Virginia, most of those in the northeastern states would face relatively low emission reduction requirements. Strict measures to control sulfur dioxide already exist in many parts of the Northeast, leaving little room for further improvement. Although the actual quantity of sulfur dioxide released in the region is lower than in many less populated areas to the south, emission sources concentrated near many urban centers have caused high atmospheric levels. This has prompted strict SO_2 control measures on nearby combustion sources, including large numbers of coal- and oil-fired utilities. Thus, emissions from most plants in the Northeast already are lower than the standard of 1.2 pounds of SO_2 per million Btus used in the excess emissions formula.

Overall Cost of Emission Rollback Programs

Several measures of cost are used throughout this report (see box). One important measure estimates a total stream of costs expended by the electric utility industry over a specified period to meet a SO_2 rollback. This stream of costs--summed and discounted over the 1986 through 2015 period --provides an estimate of total program costs in 1985 dollars. Thus, an 8 million ton SO_2 rollback would have a discounted program cost of $20.4 billion, assuming fuel switching was unconstrained (Option II-1A), and about $23.1 billion (in discounted 1985 dollars) assuming limits were placed

COST MEASURES USED IN THIS REPORT

This report uses several measures of cost to compare different policies. These measures attempt to account for variations in abatement levels, cost-sharing provisions, and the assumed timing of costs and emission reductions over the period considered. In this chapter, three concepts are used:

Annual Utility Cost is the cost that governs utility choices in the National Coal Model and that determines rates in the electricity price model used in this analysis (see appendix). It consists of the annual real capital and variable costs associated with the production and transmission of electricity in a given year, usually 1995 for the base case and alternatives. These include the cost of purchasing and transporting coals to various regions, as well as those of operating power plants under specific emission limits.

Discounted Program Cost is a measure of overall utility costs incurred from 1986 through 2015 to meet an SO_2 emission reduction policy. (The 1986-2015 time frame simply represents the period over which most rollback costs likely will be incurred.) A stream of annual real utility costs first are estimated for each year during the 1986-2015 period, based on results from the NCM; this series is discounted by 3.7 percent and then summed to give discounted program costs as a net present value (producing discounted 1985 dollars). (Discounting converts future dollar figures to their value in an earlier year, reflecting the notion that a dollar held in the future is worth less than one held today).

Cost-Effectiveness is a measure that represents average abatement costs over the 1986-2015 period. This measure takes into account the amount of emission rollback, but assigns no dollar value to the benefits that might accrue from them. The numerator of this fraction is simply discounted program costs as calculated above. The denominator consists of a summed series of discounted (at 3.7 percent) annual emission reductions relative to the base case (roughly representing the value of benefits obtained). For a given emission reduction over the period, one policy can be more cost-effective than another--that is, expend fewer dollars per ton of SO_2 reduced--if its costs are lower or if they occur later. Likewise, for a given stream of costs, a policy can be more cost-effective than another if its emission reduction is greater or if it occurs earlier.

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TABLE 3. PROJECTED 1995 EMISSIONS FOR 8 AND 10 MILLION TON SO_2 REDUCTION PROGRAMS, BY STATE [a] (In thousands of tons of SO_2)

State	Base Case 1985	Base Case 1995	8 Million Ton Reduction Option II-1A	8 Million Ton Reduction Option II-1B	10 Million Ton Reduction Option II-2A	10 Million Ton Reduction Option II-2B
Alabama, Mississippi	586	704	489	489	414	415
Arizona	114	122	117	117	106	115
Arkansas, Oklahoma, Louisiana	200	336	304	292	302	293
California	3	25	25	25	25	25
Carolinas, North and South	728	1,063	606	615	577	577
Colorado	71	92	94	94	94	90
Dakotas, North and South	60	105	105	105	105	105
Florida	489	772	605	568	566	546
Georgia	731	635	407	403	352	341
Idaho	0	0	0	0	0	0
Illinois	1,071	1,142	566	566	408	408
Indiana	1,210	1,433	799	800	553	554
Iowa	259	326	192	193	167	167
Kansas, Nebraska	154	174	167	173	163	165
Kentucky	707	796	512	527	466	449
Maine, Vermont, New Hampshire	109	64	56	59	44	45
Maryland, Delaware	282	371	215	215	189	189
Massachusetts, Connecticut, Rhode Island	294	305	241	241	219	219
Michigan	525	598	423	414	374	374
Minnesota	176	230	159	159	146	146

(Continued)

TABLE 3. (Continued)

State	Base Case 1985	Base Case 1995	8 Million Ton Reduction Option II-1A	8 Million Ton Reduction Option II-1B	10 Million Ton Reduction Option II-2A	10 Million Ton Reduction Option II-2B
Missouri	1,133	1,257	482	483	293	295
Montana	71	71	68	73	68	69
Nevada	75	90	80	80	80	80
New Mexico	43	62	62	62	62	62
New York (Downstate), New Jersey	269	270	247	247	245	242
New York (Upstate)	325	343	193	193	141	143
Ohio	1,901	2,017	963	963	629	629
Pennsylvania	1,345	1,439	839	839	578	599
Tennessee	676	761	421	421	281	281
Texas	369	586	569	571	567	569
Utah	45	87	61	63	61	63
Virginia, District of Columbia	97	213	180	176	175	173
Washington, Oregon	37	111	108	102	104	98
West Virginia	968	1,042	511	512	421	417
Wisconsin	574	746	272	272	199	200
Wyoming	58	69	70	69	70	69
Total	15,756	18,455	11,208 b/	11,179 b/	9,241 b/	9,209 b/

SOURCE: Congressional Budget Office.

a. To permit greater computational efficiency, the National Coal Model groups some states or portions of states into common regions.

b. Neither the 8 million ton nor the 10 million ton rollback options would meet the goal specified if measured against 1995 base case emissions because of growth in new source emissions after 1980, the baseline year for measuring reductions.

on the amount of fuel switching allowed (Option II-1B). Similarly, the discounted program cost of a 10 million ton SO_2 rollback would range from \$34.5 billion (Option II-2A) to \$50.8 billion (Option II-2B), depending on whether fuel switching was allowed or restricted (all in discounted 1985 dollars). Table 4 shows total program costs and cost-effectiveness estimates of each rollback option compared with current policy.

The cost-effectiveness figures shown in Table 4 provide a different measure from program costs, one closely related to average abatement cost. These represent the discounted program costs under each option divided by the amount of SO_2 reduced from current policy levels over the 1986-2015 period. They show that, under either program, emission reductions would be cheaper if the coal market is unrestricted. When fuel switching is allowed, the average annual cost to abate one ton of SO_2 would be \$270 under an 8 million ton program (Option II-1A). When an attempt is made to restrict fuel switching, this number jumps to \$306 per ton of SO_2 abated (Option II-1B). Likewise, a 10 million ton SO_2 reduction would cost \$360 per ton of

TABLE 4. COMPARISON OF TOTAL PROGRAM COSTS AND COST-EFFECTIVENESS OF TWO ROLLBACK PROGRAMS

	8 Million Ton SO_2 Reduction		10 Million Ton SO_2 Reduction	
	Option II-1A	Option II-1B	Option II-2A	Option II-2B
Total Program Cost (In billions of discounted 1985 dollars) a/	20.4	23.1	34.5	50.8
Cost-Effectiveness (In discounted 1985 dollars per ton of SO_2 reduced) b/	270	306	360	528

SOURCE: Congressional Budget Office.

a. Reflects present value of sum of annual utility costs incurred from 1986 through 2015, discounted to 1985 dollars. A real discount rate of 3.7 percent was used in the calculations.

b. Represents the discounted program costs, divided by the annual discounted SO_2 reductions measured over the 1986-2015 period.

SO_2 abated when coal markets are not restricted (Option II-2A), compared with \$528 a ton when fuel choices are limited to maintain current patterns. In each case, costs would increase because more scrubbers would have to be used to meet emission standards.[12] Moreover, the marginal cost of emission reductions would rise as abatement targets increased from 8 million tons to 10 million tons.

Annual Cost to Utilities. The annual cost to utilities for an 8 million ton SO_2 rollback program would range between \$1.9 billion (Option II-1A) and \$2.1 billion (Option II-1B), based on the 1995 cost difference between current policy and each option (see Table 5). Similarly, a 10 million ton program would cost utilities between \$3.2 billion (Option II-2A) and \$4.7 billion (Option II-2B) per year in 1995 (see Table 6). The difference between the higher and lower costs of each option depends on whether current coal-market patterns are preserved (more scrubbers would be needed if current coal contracts are kept) or whether fuel switching would be allowed as a compliance strategy. If fuel switching is restricted, roughly \$8.8 billion in capital would be needed above current policy between 1986 and 1995 to meet the 8 million ton reduction, and about \$25.2 billion more would be needed to meet the 10 million ton reduction. If fuel switching is allowed (which would lower scrubbing requirements) the additional capital requirements between 1986 and 1995 would be greatly reduced: \$4.4 billion versus \$8.8 billion would be needed under the 8 million ton case and \$11.2 billion versus \$15.2 billion under the 10 million ton case. These large savings in expected capital outlays would more than offset the higher costs of using lower-sulfur fuel.

Two general patterns emerge from the effect of a SO_2 emissions rollback on annual utility costs, although each has several exceptions. First, utilities in Pennsylvania, West Virginia, Ohio, Indiana, Illinois, and Missouri would bear about half of the total cleanup costs, regardless of whether coal switching occurs or whether the required SO_2 reduction is 8 million tons or 10 million tons. Thus, utilities in these states would face annual costs in

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12. Recent oil price reductions have two implications for this analysis. First, should oil prices continue to fall or remain stable in real terms until 1995, the overall cost of each option could fall, partly from reduced costs in existing oil-fired plants and partly from plants shifting from more expensive gas to less expensive oil (for those plants capable of using either fuel). A possible countervailing trend, however, is the potential for increased electricity demand as prices fall. Second, if oil prices remain lower than expected, rail rates--especially for long-haul shipments--might not be as costly as once thought. Thus, greater than expected western coal penetration into eastern markets might occur under an acid rain control plan, making coal-market restrictions even more costly. In both cases, while falling oil prices might lower the absolute costs of each option described in this study, the relative rankings between them would remain unchanged. See the appendix for more details.

TABLE 5. ANNUAL UTILITY COSTS AS OF 1995 OF 8 MILLION TON SO_2 ROLLBACK, BY STATE (In millions of 1985 dollars)

State	Base Case 1995	Option II-1A	Option II-1B	Difference from 1995 Base Case: Option II-1A	Difference from 1995 Base Case: Option II-1B
Alabama, Mississippi	4,224	4,307	4,291	83	67
Arizona	1,944	1,930	1,954	-15	10
Arkansas, Oklahoma, Louisiana	9,591	9,698	9,716	107	125
California	10,565	10,722	10,747	157	182
Carolinas, North and South	4,759	4,886	4,845	127	86
Colorado	1,093	1,097	1,114	4	21
Dakotas, North and South	567	565	569	-1	3
Florida	6,127	6,202	6,204	75	77
Georgia	2,555	2,618	2,601	63	45
Idaho	221	221	221	0	0
Illinois	4,189	4,312	4,278	124	89
Indiana	3,095	3,202	3,200	107	105
Iowa	1,230	1,288	1,304	58	74
Kansas, Nebraska	1,854	1,860	1,863	7	9
Kentucky	3,103	3,170	3,142	68	40
Maine, Vermont, New Hampshire	1,123	1,119	1,121	-4	-2
Maryland, Delaware	1,885	1,853	1,698	-32	-186
Massachusetts, Connecticut, Rhode Island	3,513	3,633	3,629	120	116

(Continued)

TABLE 5. (Continued)

State	Base Case 1995	Option II-1A	Option II-1B	Difference from 1995 Base Case: Option II-1A	Difference from 1995 Base Case: Option II-1B
Michigan	2,817	2,874	2,865	57	48
Minnesota	1,186	1,184	1,223	-2	37
Missouri	2,024	2,137	2,150	113	126
Montana	676	675	681	-1	5
Nevada	1,096	1,122	1,120	25	24
New Mexico	1,158	1,138	1,163	-21	5
New York (Downstate), New Jersey	4,878	4,902	4,894	25	16
New York (Upstate)	2,395	2,443	2,437	48	41
Ohio	4,239	4,397	4,378	158	138
Pennsylvania	5,512	5,711	5,925	199	413
Tennessee	2,078	2,118	2,133	40	55
Texas	15,852	15,834	15,840	-18	-12
Utah	1,345	1,367	1,357	22	12
Virginia, District of Columbia	1,884	1,923	1,925	39	41
Washington, Oregon	4,219	4,147	4,155	-72	-64
West Virginia	1,784	1,936	2,028	153	244
Wisconsin	1,572	1,671	1,707	98	135
Wyoming	1,026	1,034	1,032	8	6
Total	117,380	119,298	119,510	1,919	2,130

SOURCE: Congressional Budget Office.

TABLE 6. ANNUAL UTILITY COSTS AS OF 1995 OF 10 MILLION TON SO_2 ROLLBACK, BY STATE (In millions of 1985 dollars)

State	Base Case 1995	Option II-2A	Option II-2B	Difference from 1995 Base Case: Option II-2A	Difference from 1995 Base Case: Option II-2B
Alabama, Mississippi	4,224	4,364	4,557	140	333
Arizona	1,944	1,943	1,951	-2	6
Arkansas, Oklahoma, Louisiana	9,591	9,723	9,778	132	187
California	10,565	10,822	10,849	257	284
Carolinas, North and South	4,759	4,895	4,829	136	70
Colorado	1,093	1,100	1,134	7	41
Dakotas, North and South	567	565	570	-1	3
Florida	6,127	6,198	6,184	71	57
Georgia	2,555	2,622	2,602	67	46
Idaho	221	221	221	0	0
Illinois	4,189	4,432	4,404	244	216
Indiana	3,095	3,233	3,477	139	382
Iowa	1,230	1,327	1,216	97	-15
Kansas, Nebraska	1,854	1,862	1,958	8	104
Kentucky	3,103	3,499	3,500	396	398
Maine, Vermont, New Hampshire	1,123	1,123	1,125	0	2
Maryland, Delaware	1,885	1,654	1,707	-231	-178
Massachusetts, Connecticut, Rhode Island	3,513	3,678	3,669	165	156

(Continued)

TABLE 6. (Continued)

State	Base Case 1995	Option II-2A	Option II-2B	Difference from 1995 Base Case: Option II-2A	Difference from 1995 Base Case: Option II-2B
Michigan	2,817	2,944	2,911	127	94
Minnesota	1,186	1,228	1,217	42	31
Missouri	2,024	2,206	2,270	182	246
Montana	676	675	682	-1	6
Nevada	1,096	1,122	1,121	25	25
New Mexico	1,158	1,144	1,163	-14	5
New York (Downstate), New Jersey	4,878	5,200	4,892	322	14
New York (Upstate)	2,395	2,236	2,523	-160	128
Ohio	4,239	4,271	4,898	32	659
Pennsylvania	5,512	6,056	6,075	544	563
Tennessee	2,078	2,028	2,023	-51	-55
Texas	15,852	15,844	15,853	-7	2
Utah	1,345	1,368	1,359	23	13
Virginia, District of Columbia	1,884	1,926	1,921	42	37
Washington, Oregon	4,219	4,068	4,076	-151	-143
West Virginia	1,784	2,278	2,377	494	594
Wisconsin	1,572	1,734	1,981	162	408
Wyoming	1,026	1,039	1,033	12	7
Total	117,380	120,630	122,105	3,250	4,725

SOURCE: Congressional Budget Office.

1995 of about \$854 million (out of the national total of \$1.9 billion) to meet an 8 million ton SO_2 control program that allowed fuel switching (Option II-1A); if coal switching was not allowed (Option II-1B), these states would face annual costs of about \$1.1 billion compared with the national total of \$2.1 billion. Similarly, under a 10 million ton reduction program, 1995 annual costs for utilities in these six states would range between \$1.6 billion (Option II-2A) and \$2.7 billion (Option II-2B) out of the respective national totals of \$3.2 billion and \$4.7 billion, with an unencumbered coal-market policy providing the lower costs in each range. The disproportionately large costs would arise because these states would need to achieve the greatest proportion of emission reductions, regardless of whether they import costly, low-sulfur coal or install scrubbers.

These results illustrate the second trend: costs would be greatly increased if coal switching was restricted and scrubber use increased accordingly. In the 8 million ton rollback program, the option that would restrict fuel switching produces 10 percent higher costs than the option that would not (see Table 5); in the 10 million ton program, the no fuel switching case has over 50 percent higher costs (see Table 6). This implies that preserving current coal supply and demand patterns when reducing SO_2 emissions can cost more than allowing freedom of fuel choice. Individual exceptions to this condition exist, however. For example, under an 8 million ton case, it appears almost equally expensive for plants in Indiana to import and burn low-sulfur coal as it would be to burn high-sulfur coal with a scrubber (see Table 5). When a ten million ton reduction is required, however, the cost per ton of SO_2 removal (cost-effectiveness) is higher when more scrubbing is used instead of fuel switching (see Table 6).

Finally, some areas could experience lower costs in 1995 under a sulfur dioxide rollback plan than under current policy. For example, in all cases, costs in Maryland and Delaware and Washington and Oregon would fall slightly (compared with the 1995 base case) if a SO_2 emission reduction plan was instituted. One explanation is the expected decline in high-sulfur coal prices caused by the SO_2 rollback requirements (under any scenario, high-sulfur coal prices will fall while low-sulfur coal prices will rise). In such situations, plants already burning high-sulfur coal (whether or not they were using a scrubber) could experience a price reduction. Another reason is that, under a rollback program, some utilities would choose to build less new capacity or generate less power from existing plants, importing electricity from other regions instead to control emissions in their own areas. Such a choice would show lower generation costs in the region importing power since it would generate less electricity than under current policy. Consumers, however, would not necessarily benefit from this choice because the imported electricity would probably be more expensive.